Progress Energy

May 6, 2010

Ms. Jocelyn Boyd
Interim Chief Clerk/Administrator
South Carolina Public Service Commission
Post Office Drawer 11649
Columbia, South Carolina 29211

Re: Docket No. 2010-1-E

Dear Ms. Boyd:

Enclosed for filing in the subject docket are the direct testimonies of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., witnesses Bruce P. Barkley and Dewey S. Roberts II. In accordance with Commission directive in Docket No. 2005-83-A, also enclosed is a Notice of Filing. All parties of record have been served.

Very truly yours,

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

LSA:mhm

cc: Mr. John Flitter
All Parties of Record

Enclosure

STAREG962

Progress Energy Service Company, LLC
P.O. Box 1551
Raleigh, NC 27602

BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

DOCKET NO. 2010-1-E

In the Matter of:

Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., Annual Review of Base Rates For Fuel Costs	)))	**CERTIFICATE OF SERVICE**

I, Len S. Anthony, hereby certify that Progress Energy Carolinas, Inc.'s Direct Testimonies of Witnesses Bruce P. Barkley and Dewey S. Roberts II have been served on all parties of record either by hand delivery, email or by depositing said copy in the United States mail, postage prepaid, addressed as follows, this the 6th day of May, 2010:

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STAREG962

STATE OF NORTH CAROLINA)
)
) VERIFICATION
)
) DOCKET NO. 2010-1-E
COUNTY OF WAKE)

PERSONALLY APPEARED before me, Bruce P. Barkley who, after first being duly sworn, said that he is Manager – Fuel Forecasting and Regulatory Support at Progress Energy Carolinas, Inc. and as such is authorized to make this verification; that he has read the foregoing Testimony and knows the contents thereof; and that the same are true and correct to the best of his knowledge, information, and belief.

Bruce P Barkley

BRUCE P. BARKLEY

Sworn to and subscribed before me,
this the 6th day of May, 2010.

Marsha H. Manning

Marsha H. Manning, Notary Public

MARSHA H MANNING
NOTARY PUBLIC
WAKE COUNTY, NC
My Commission Expires 10-3-2014

STAREG962

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2010-1-E
DIRECT TESTIMONY OF PROGRESS ENERGY CAROLINAS, INC.

WITNESS BRUCE P. BARKLEY

Q. Please state your name, address, and position.

A. My name is Bruce P. Barkley and my business address is 100 East Davie Street, Raleigh, North Carolina. My position is Manager–Fuel Forecasting and Regulatory Support for Progress Energy Carolinas, Inc. ("PEC" or "Company")

Q. Please describe your educational background and professional experience.

A. I obtained a Bachelor of Science Degree in Business Administration with a concentration in Accounting from the University of North Carolina at Chapel Hill in 1984 and an MBA Degree from Wake Forest University in 1999. I obtained my CPA license in 1987. I joined Progress Energy in the Regulatory Services Section in 2001 and transferred to my current position in the Fuels and Power Optimization Department in 2005. I am responsible for fuel forecasting, fuel reporting and associated regulatory matters.

Q. Have you previously presented testimony regarding fuel clauses?

A. Yes, I have testified in PEC's 2003-2009 fuel cost proceedings before the Public Service Commission of South Carolina ("PSCSC") and in numerous fuel cases before the North Carolina Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

- Describe PEC's fuel procurement practices and costs for the historical period under review in this proceeding, March 2009 through February 2010, and support the reasonableness of these costs.

- Present projected fuel costs for the period March 2010 through June 2011.
- Recommend fuel factors to be effective July 1, 2010.

My testimony will include a review of historical and projected environmental costs and a recommended rate for recovery of these costs. The environmental portion of the fuel rate includes the cost of ammonia and limestone used in the process of reducing sulfur dioxide (SO_2) and nitrous oxide (NO_x) emissions and the cost of SO_2 and NO_x emission allowances. I will provide thirteen exhibits to support my testimony.

Q. Please summarize key fuel cost and inventory information for the review period.

A. Barkley Exhibit No. 1 summarizes PEC's fossil fuel costs for the review period, including quantities purchased and consumed and the beginning and ending inventory levels. The price of delivered coal increased by $4.90 per ton, (5.5%), as compared to the prior review period, to approximately $94 per ton. This increase in delivered coal price was primarily attributable to the expiration of coal contracts that were signed prior to the significant price spike that occurred in 2008. The price of natural gas decreased by $2.68 (25%) per million British thermal units (mmbtu) as compared to the prior review period. I will address changes in the market price of coal and natural gas later in my testimony. The inventory levels maintained by PEC as shown on Exhibit 1 were adequate.

Q. Please describe the Company's coal procurement practices.

A. PEC continues to follow the same procurement practices that it has historically followed. These practices include determining and continuously monitoring coal consumption and inventory requirements; maintaining a list of qualified suppliers; conducting formal requests for proposals on a staggered basis; prudently combining market purchases and long term contracts and monitoring supplier and rail performance. A summary of these practices is shown on Barkley Exhibit No. 13.

Q. Please describe the state of the coal market during the historical review period.

A. Barkley Exhibit No. 2 illustrates the movement of coal prices since 2006, most notably the significant volatility of prices experienced during 2008. During the review period ended February 28, 2010, market price prices initially decreased and then returned to approximately the same level as experienced at the beginning of the period. The strengthening of prices during the second half of 2009 and continuing through the end of the review period was attributable to indicators of worldwide economic recovery and to decreasing coal production. Supply reductions were primarily based upon the weak economy that existed during 2009 and the associated decline in the price of coal.

Q. What are PEC's expectations for the forecasted period ending June 30, 2011?

A. As shown on my Exhibit No. 2, the market price of coal is expected to increase during the forecasted period. Demand is expected to increase due to anticipated economic growth and the challenges faced by coal mining companies to maintain or expand coal supply persist. As discussed in my testimony in prior annual fuel review proceedings, factors negatively impacting coal supply include a shortage of labor, difficult permitting requirements for new mines and increased costs associated with miner safety and environmental regulations. PEC projects that its cost of coal consumed during the forecasted period will be approximately $62 per ton as compared with the approximately $67 per ton forecasted in last year's proceeding. Most of PEC's coal continues to be received under contracts ranging from one to three years in duration and the principal reason for the decline in the expected price of coal consumed is the expiration of certain contracts and subsequent replacement with contracts at current market values. However, I expect increasing coal costs in future annual proceedings based on the demand and supply trends outlined previously. I also expect the market price of coal to exhibit volatility, particularly in response to revised expectations of economic recovery and to legislation impacting coal.

Q. How does the Company select coal and what coals are likely to be selected in future periods as a result of this process?

A. Evaluations of PEC's long-term and short-term coal needs are made from the standpoint of obtaining a reliable supply of coal at the lowest total cost. Items considered include coal price, coal quality, transportation cost, operating costs such as the limestone and ammonia needed to operate pollution control devices, maintenance costs, emission allowance costs and any associated capital costs. PEC uses a wide variety of procurement options through its supplier bidding process in order to obtain the best-priced coal for its generating fleet. At this time, the most economical coal for PEC's units with installed scrubbers is sourced from the Central Appalachia (CAPP) region and contains approximately three pounds of SO_2 per mmbtu. For the units that do not have scrubbers installed, the most economical coal is also sourced from the CAPP region and contains approximately two pounds of SO_2 per mmbtu. PEC will continue to actively pursue coals of varying qualities and geographic origins in order to obtain the most secure and economical coal supply.

Q. Please describe PEC's policies associated with long term coal contracting.

A. PEC hedges its coal costs by entering into long term contracts at fixed prices for a significant portion of its projected coal needs. Any additional coal requirements are purchased on the spot market as needed to maintain inventories. PEC staggers contract expiration dates so that a portion of the contracts expire each year and is replaced with new contracts of corresponding duration, similar to the investing strategy known as dollar cost averaging. PEC targets a minimum of 85% of its projected needs for the current year to be under contract. The minimum amounts under contract targets are 60%, 40%, 20% and 5% for years 2-5. Contracts beyond five years may be pursued if appropriate terms and conditions can be established. This structure of tiered contracts provides a reasonable degree of cost stability and allows the Company to respond appropriately to market trends, either upward or downward. PEC has entered contracts for approximately 83% of its coal requirements for the forecasted period ending June 30, 2011. These contracts will enhance the reliability of coal supply over the forecasted period and reduce price volatility.

Q. How is coal transported to PEC?

A. Coal is generally transported by rail using either the CSX railway or the NS railway. PEC receives a limited amount of coal by truck at Asheville and has received foreign coal by barge at the Sutton Plant located near Wilmington, NC.

Receipt points for coal delivered by rail are generally in the CAPP region, but can include coal delivered to the port at Charleston, SC. The Roxboro and Mayo plants, PEC's largest coal plants, and the Asheville plant are served solely by NS. Three other plants are served solely by CSX and two plants can be served by either rail provider. To minimize transportation costs, PEC negotiates the most advantageous rates reasonably possible and participates, through a consortium of shippers, in proceedings before the Federal Surface Transportation Board. PEC's use of water and truck transportation demonstrates its continuing commitment to diversification of coal transportation.

Q. Do you currently expect major changes to transportation costs during the forecasted period?

A. No, I do not. However, indices related to inflation and oil prices are variables which impact PEC's freight costs.

Q. What steps has PEC taken to reduce coal costs in light of the significant changes in market prices experienced over the past two years?

A. As outlined in Barkley Exhibit No. 13, PEC carefully monitors supplier and freight performance to ensure compliance with established contracts. PEC continuously engages the market and evaluates a wide variety of suppliers and types of coals including those of varying sulfur and heat content, maintaining maximum supply flexibility and the opportunity for potential cost savings. The Company has and will continue to invest in its coal-fired generating units in order to facilitate the consumption of a wide variety of coal types. Further, PEC will obtain the most economical and flexible modes of transportation. Finally, the Company will continue to adhere to its disciplined strategy of procuring most of its coal under contractual arrangements of varying lengths and vintages.

Q. Please describe your procurement practices for natural gas.

A. PEC follows a process that is very similar to that discussed earlier for coal. Production costing models are used to project future demands. Based on the projections, requests for proposals are made, bids received, and contracts based on monthly and daily price indicies are established to cover a minimum of 85% of the projected requirement for the coming year. Declining percentages of firm needs are obtained for periods of up to four years. Long term contracts are established and maintained for gas transportation. On a short term basis, additional purchases on the spot market are made as needed to manage the Company's natural gas requirements.

Q. Please describe the state of the natural gas market and PEC's expectations for the forecasted period.

A. Natural gas market prices are shown on Barkley Exhibit No. 3. Prices have declined dramatically since the peak in the summer of 2008 in light of the global recession and the continued success of production coming from unconventional domestic shale formations. Including hedges and excluding fixed costs, PEC's forecasted delivered cost of natural gas for the year ending June 30, 2011 is $6.85 per mmbtu which is approximately $.59 per mmbtu lower than the amount forecasted in last year's proceeding.

Q. How has the shale gas you mentioned impacted the outlook for natural gas?

A. Primarily due to the development of shale gas reserves and advanced methods of drilling, North American natural gas resources have approximately doubled over the past three years resulting in an amount of natural gas that could supply current levels of consumption for more than one hundred years. Shale gas is expected to grow to more than 50% of domestic supply by 2030. Importantly, the shale formations are not located in the Gulf of Mexico and are much more secure from disruptions than offshore production which can be negatively impacted by hurricanes.

Q Please discuss PEC's historical hedging practices for natural gas.

A. PEC began executing fixed price contracts for a portion of its natural gas requirements in 2005 in response to increased natural gas consumption and the volatility of natural gas market prices. Hedging via financial instruments was subsequently added. PEC's targeted natural gas price assurance range is 50% to 80% of estimated consumption for the calendar year. Ranges decrease progressively in succeeding years.

Q. What were the results of PEC's natural gas hedging program for the review period?

A. During the review period, hedged natural gas costs were $96 million higher than an equivalent amount of market-priced gas.

Q. What caused these hedging losses?

A. The losses were due to unexpected price declines that occurred after the hedges were put in place. Prices began to decline in July 2008 due to the impacts caused by the recession and the realization that unconventional shale production had increased at a faster rate than previously estimated and could be successfully produced at lower prices. At its lowest point during the summer of 2009, the daily average natural gas price at the Henry Hub was below $2 per mmbtu. For comparison, prices during the summer of 2008 peaked at over $13 per mmbtu. For additional comparison, the value of the PEC's natural gas hedges for the review period February 2009 through March 2010 was positive by approximately $60 million based on market conditions as of July 1, 2008. During the review period, PEC's hedged volumes represented approximately 55% of its natural gas consumption. For the 45% of natural gas consumption that was obtained via the spot market, PEC was able to take advantage of market prices that approximated $4 per mmbtu over the review period.

Q. Has PEC adjusted its hedging approach in light of the shale gas proliferation?

A. Yes, it has. The Company believes that the amount of domestic shale gas being produced will continue to impact natural gas prices. Although volatility will continue, prices should be reduced by the continued growth in domestic supply. As a result of these developments, PEC is targeting to hedge at the lower end of its established hedging targets and is not hedging beyond a rolling 36-month period.

Q. Should PEC continue hedging for natural gas?

A. Yes. A cessation of hedging would expose customers to price risk and volatility. PEC's annual natural gas usage is expected to increase significantly from current levels and will be a larger component of PEC's overall fuel mix as approximately 2100 megawatts of new combined cycle gas generation is added at Richmond County, Wayne County and the proposed Sutton facility over the next few years.

Natural gas prices continue to be volatile and can have large percentage changes day to day, even though prices have declined from historic highs. For example, on April 29, 2010, the June 2010 NYMEX contract changed by approximately 8.5%. PEC has prudently reduced its targeted percentage and time horizon for hedging in light of the evolving market realities previously discussed.

Q. Does PEC purchase power and how are these costs recorded?

A. Yes. As explained by PEC witness Roberts, PEC continuously evaluates purchasing power if it can be reliably procured and delivered at a price that is less than the variable cost of PEC's generation. In accordance with S.C. Code Ann. § 58-27-865(A), PEC includes the lower of the purchase price or PEC's avoided variable cost for generating an equivalent amount of power for its economy purchases. PEC also purchases power from certain vendors that are treated as firm generation capacity purchases. In accordance with the statute, all costs from these counterparties are recorded as recoverable fuel costs with the exception of capacity charges.

Q. Please explain Barkley Exhibit No. 4

A. Barkley Exhibit No. 4 is a summary of PEC's actual system fuel cost experienced during the period March 2009 through February 2010. Total system fuel costs were $1,582,779,760.

Q. How did the fuel revenue billings compare to the actual fuel costs incurred during the historical period March 2009 through February 2010?

A. Barkley Exhibit No. 5 is a monthly comparison of fuel revenues billed to South Carolina retail customers to the actual fuel costs attributable to those sales. PEC's under-recovery of fuel costs decreased from $10.3 million at February 28, 2009 to $4.1 million at February 28, 2010.

Q. Please explain Barkley Exhibit No. 6.

A. Barkley Exhibit No. 6 presents PEC's recommended fuel rate of 2.723 ¢/kWh for the 12-month period July 2010 through June 2011, consisting of a component for recovery of projected fuel expense of 2.703¢/kWh and a component to collect the projected under-recovery at June 30, 2010 of .020¢/kWh. The projected under-recovery at June 30, 2010 is $1,283,206 as shown on my Exhibit No. 7.

The fuel forecast supporting the projected fuel cost was generated by an hourly dispatch model that considers the latest forecasted fuel prices, outages at the generating plants based on planned maintenance and refueling schedules, forced outages based on historical trends, generating unit performance parameters and expected market conditions associated with power purchase and off-system sales opportunities.

Q. Please explain Barkley Exhibit No. 7.

A. Barkley Exhibit No. 7 provides projected costs and revenues, by month, for the period March 2010 through June 2011. The exhibit continues the use of the currently approved fuel factor of 3.002¢/kWh through June 2010 and includes PEC's recommended factor of 2.723 ¢/kWh for the period July 2010 through June 2011. PEC's proposed fuel factor practically eliminates the deferred fuel balance as of June 30, 2011.

Q. Please provide a status update of environmental cost collection and explain how these costs have been treated in this filing.

A. In 2007, the General Assembly passed legislation that allows utilities to recover the costs of ammonia, lime, limestone, urea, dibasic acid, catalysts and emission allowances through an annual environmental cost rider. Environmental costs allocated to the SC retail jurisdiction during the review period were approximately $2.3 million as shown on Barkley Exhibit No. 8. The deferred account balance for environmental costs changed from an overcollection at February 28, 2009 of $380,939 to an overcollection at February 28, 2010 of $715,944.

Q. Have you provided a forecast of environmental costs?

A. Yes. Barkley Exhibit No. 9 includes PEC's estimated environmental costs for the period from July 2010 through June 2011. The forecasted environmental expense for the year ending June 30, 2011 is $21,548,384. The SC retail portion is forecasted to be approximately $2.6 million which is slightly less than the $2.9 million forecasted in the 2009 proceeding. PEC currently estimates that its environmental cost overcollection will be $387,233 at June 30, 2010 as shown on Exhibit No. 10. PEC proposes to return this amount to customers during the period from July 2010 through June 2011 and thereby virtually eliminate the deferred account balance for environmental cost as of June 30, 2011.

Q. How did PEC allocate environmental costs?

A. Costs were allocated consistently with the Commission's Orders in PEC's 2008 and 2009 fuel proceedings. Environmental costs were allocated to Residential, General Service (non-demand), General Service (demand) and Lighting rate classes based upon the coincident peak experienced during the review period. This allocation is shown on Barkley Exhibit No. 9. Rates were designed based on costs allocated to the respective rate classes and the projected energy consumption for the residential, general service (non-demand) and lighting schedules. The rate for the general service (demand) class was based on projected annual demand in a manner consistent with the methodology approved by the PSCSC in 2008 and 2009.

Q. Have you presented PEC's proposed fuel factors?

A. Yes. Barkley Exhibit No. 11 presents proposed fuel rates including an amount added to account for the 5% discount provided to residential customers under PEC's approved Residential Service Energy Conservation Discount Rider RECD-2B.

Q. Why does PEC propose inclusion of the effects of Rider RECD-2B in this proceeding?

A. The method historically used by PEC to compare fuel costs with fuel revenue assumed that all customers paid the full fuel factor for each kWh consumed. But this is not the case for customers enjoying the 5% discount. Failure to recognize the impact of the 5% discount results in an overstatement of PEC's fuel revenues and an understatement of amounts owed to PEC by its customers. PEC should not reflect fuel revenue collections for 100% of its fuel billings while simultaneously providing a 5% discount on the total bill as required by Rider RECD-2B. As shown on Barkley Exhibit No. 12, this discount impacts approximately 16% of PEC's SC residential consumption.

Q. Was the 5% recognized and accounted for in PEC's 2009 fuel review proceeding?

A. Yes. PEC's request in this proceeding is consistent with the request made in its 2009 proceeding.

Q. Were PEC's fuel and environmental costs prudently incurred during the review period?

A. Yes. PEC's fuel and environmental costs were prudently incurred and accurately recorded and are fully recoverable pursuant to South Carolina law. As discussed by PEC witness Roberts, PEC prudently operated its generation resources during the period under review in order to minimize its fuel costs and purchased power when doing so was cost effective.

Q. Does that complete your testimony?

A. Yes, it does.

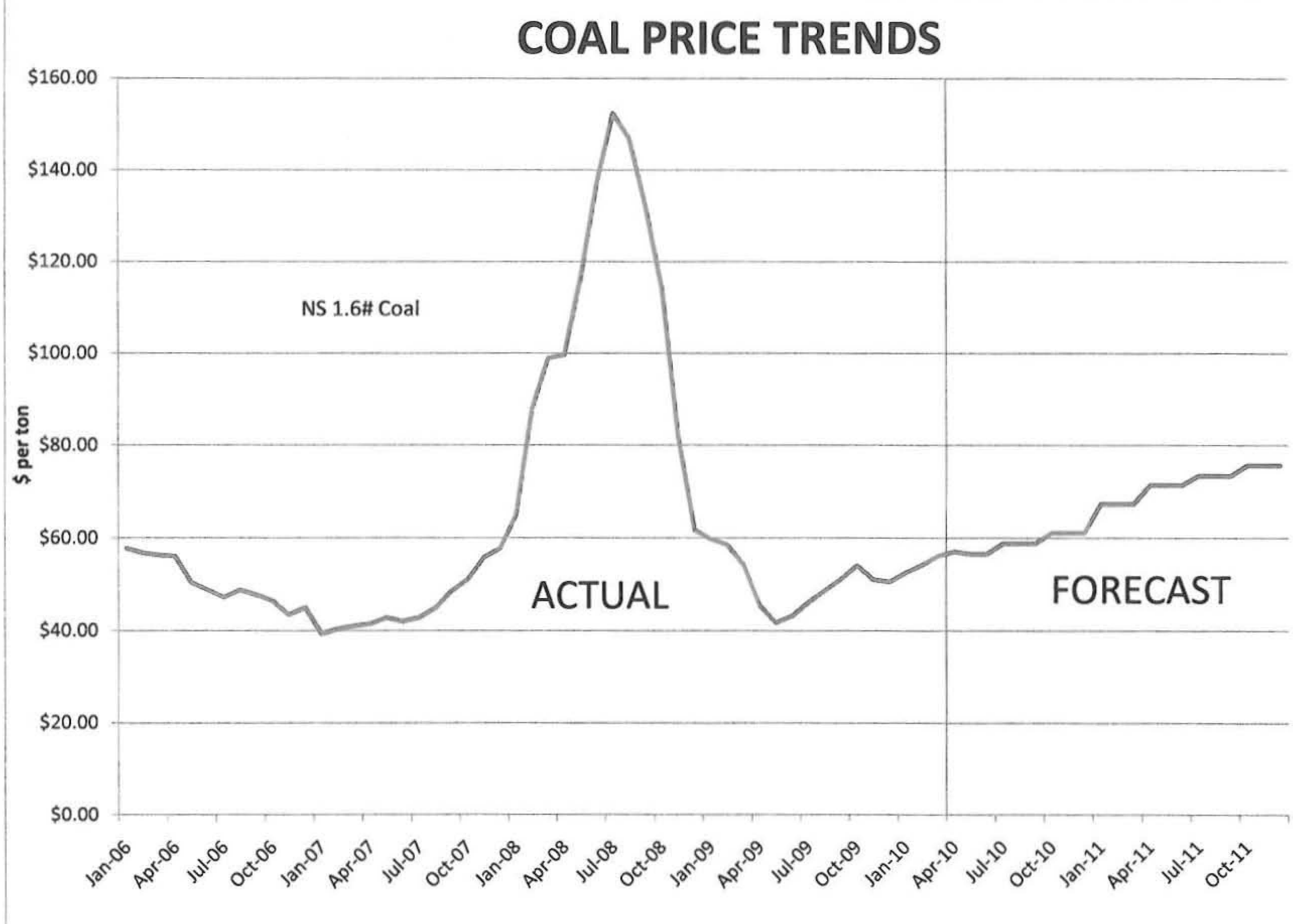
PROGRESS ENERGY CAROLINAS, INC.
FUEL CONSUMED, PURCHASED AND INVENTORIED
FOR THE TWELVE MONTHS ENDED FEBRUARY 28, 2010

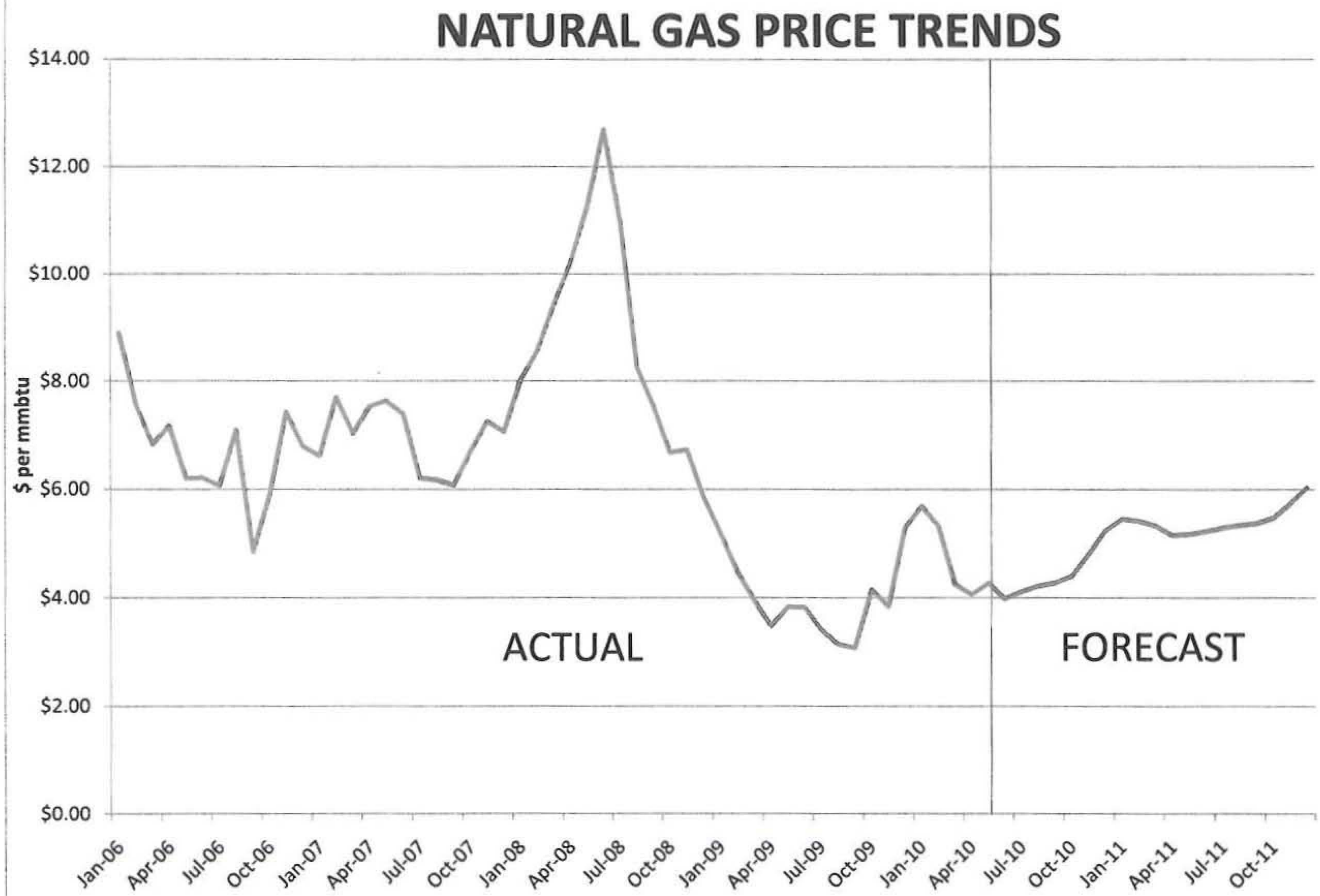
COAL			Tons	$/Ton
	Consumed		12,067,421	$93.71
	Coal Purchased		11,361,395	$71.62
	Freight Purchased		11,361,395	$22.18
	Total Purchased		11,361,395	$93.80
	$/mmbtu consumed	$3.83		
OIL			Gallons	$/Gallon
	Consumed		12,844,594	$2.01
	Purchased		13,465,260	$2.04
	$/mmbtu consumed	$14.50		
NATURAL GAS			mmbtu	$/mmbtu
	Consumed		32,449,971	$7.90
	Purchased		32,408,278	$7.91

INVENTORIES AS OF FEBRUARY 28

	2009 Units	2009 $/Unit	2010 Units	2010 $/Unit
Coal (tons)	2,198,314	$93.73	1,492,287	$94.51
Oil (gallons)	42,052,346	$1.73	30,617,288	$1.74
Natural Gas (mmbtu)	145,580	$5.00	103,887	$7.39

Barkley Exhibit No. 2
Docket No. 2010-1-E





Actual - NYMEX Last Day Settle Prices
Forecast - NYMEX Settle Prices as of 04/29/2010
Henry Hub Prices

Barkley Exhibit No. 3
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

SYSTEM FUEL COST
SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2010-1-E
TWELVE MONTHS ENDED FEBRUARY 2010

Line		Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09
(1)	Coal	$90,717,571.07	$82,979,224.19	$84,154,419.01	$94,364,938.15	$95,987,361.88	$100,961,698.97
(2)	Oil - Steam	863,652.42	1,105,995.90	1,394,583.07	1,247,556.48	1,330,326.60	949,024.30
(3)	Oil - Turbine	2,721,154.28	277,984.75	870,413.04	166,221.22	92,241.12	228,850.28
(4)	Gas - Turbine	21,524,846.69	13,991,585.52	14,430,069.17	25,285,555.09	31,647,726.84	37,861,435.21
(5)	**Total Fossil**	115,827,224.46	98,354,790.36	100,849,484.29	121,064,270.94	129,057,656.44	140,001,008.76
(6)	**Nuclear Fuel**	8,526,119.43	6,972,362.59	11,199,412.48	12,320,642.33	12,957,757.58	12,867,936.18
(7)	**Purchased Power**	16,141,183.56	15,299,573.60	9,506,038.17	13,546,837.64	15,549,119.92	16,846,176.49
(8)	**Off-System Sales**	(9,740,245.35)	(8,632,750.55)	(8,343,846.71)	(7,695,771.57)	(7,748,267.10)	(9,932,283.95)
(9)	**Total Fuel Costs**	$130,754,282.10	$111,993,976.00	$113,211,088.23	$139,235,979.34	$149,816,266.84	$159,782,837.48

Line		Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Twelve Months Ended Feb-10
(10)	Coal	$76,161,848.41	$78,066,919.56	$74,294,907.09	$114,608,145.52	$121,522,208.70	$116,961,809.05	$1,130,781,051.60
(11)	Oil - Steam	984,968.79	1,257,660.99	1,277,610.40	884,258.31	794,833.18	575,568.12	$12,666,038.56
(12)	Oil - Turbine	106,743.92	86,121.05	84,453.75	834,932.95	6,854,256.86	842,872.06	$13,166,245.28
(13)	Gas - Turbine	28,652,464.67	8,815,119.14	12,248,831.14	15,668,413.21	27,465,337.84	17,732,958.17	$255,324,342.69
(14)	**Total Fossil**	105,906,025.79	88,225,820.74	87,905,802.38	131,995,749.99	156,636,636.58	136,113,207.40	1,411,937,678.13
(15)	**Nuclear Fuel**	10,450,189.65	12,745,700.16	11,842,186.38	13,095,790.87	12,929,165.38	10,930,072.76	$136,837,335.79
(16)	**Purchased Power**	13,124,900.62	3,678,450.68	3,171,483.25	10,698,574.56	19,404,592.67	10,159,224.34	$147,126,155.50
(17)	**Off-System Sales**	(8,318,342.90)	(8,163,291.11)	(5,354,870.78)	(13,912,992.04)	(13,572,389.85)	(11,706,357.35)	(113,121,409.26)
(18)	**Total Fuel Costs**	$121,162,773.16	$96,486,680.47	$97,564,601.23	$141,877,123.38	$175,398,004.78	$145,496,147.15	$1,582,779,760.16

Barkley Exhibit No. 4
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

Comparison of Actual Fuel Revenues and Expenses
SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2010-1-E
TWELVE MONTHS ENDED FEBRUARY 2010

Line		Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09
(1)	Total Fuel Costs [$]	$130,754,282.10	$111,993,976.00	$113,211,088.23	$139,235,979.34	$149,816,266.84	$159,782,837.48
(2)	Actual SC Retail Sales [KWH]	514,268,059	450,243,429	446,254,038	532,981,714	594,209,418	604,234,009
(3)	Total System KWH Sales (Exc. Power Agency)	4,383,385,756	3,822,148,872	3,802,499,057	4,561,692,198	5,017,800,861	5,097,409,080
(4)	SC Allocation Factor	0.1173	0.1178	0.1174	0.1168	0.1184	0.1185
(5)	Revenue Required [$]	$15,337,477	$13,192,890	$13,290,982	$16,262,762	$17,738,246	$18,934,266
(6)	Revenue Billed [$]	$16,201,448	$14,187,928	$14,067,464	$16,790,414	$17,837,358	$18,138,521
(7)	Over (Under) Recovery [$]	$863,971	$995,038	$776,482	$527,652	$99,112	($795,745)
(8)	Accounting Adjustments [$]	$0	$188,492	$0	$0	$0	$0
(9)	Cumulative Under Recovery [$]	$9,483,118	$8,299,588	$7,523,106	$6,995,454	$6,896,342	$7,692,087

Line		Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Twelve Months Ended Feb-10
(10)	Total Fuel Costs [$]	$121,162,773.16	$96,486,680.47	$97,564,601.23	$141,877,123.38	$175,398,004.78	$145,496,147.15	$1,582,779,760.16
(11)	Actual SC Retail Sales [KWH]	521,514,158	495,063,511	465,377,783	501,208,977	617,291,596	557,043,705	6,299,690,397
(12)	Total System KWH Sales (Exc. Power Agency)	4,593,082,326	3,949,606,098	3,720,845,973	4,399,250,066	5,400,447,065	4,769,193,706	53,517,361,058
(13)	SC Allocation Factor	0.1135	0.1253	0.1251	0.1139	0.1143	0.1168	
(14)	Revenue Required [$]	$13,751,975	$12,089,781	$12,205,332	$16,159,804	$20,047,992	$16,993,950	$186,005,457
(15)	Revenue Billed [$]	$15,654,557	$14,860,372	$13,971,049	$15,048,761	$18,534,680	$16,725,248	$192,017,801
(16)	Over (Under) Recovery [$]	$1,902,582	$2,770,591	$1,765,717	($1,111,043)	($1,513,312)	($268,702)	$6,012,344
(17)	Accounting Adjustments [$]	$0	$0	$0	$0	$0	$17,187	$205,679
(18)	Cumulative Under Recovery [$]	$5,789,505	$3,018,914	$1,253,196	$2,364,239	$3,877,552	$4,129,066	

Barkley Exhibit No. 5
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - DOCKET 2010-1-E
CALCULATION OF BASE FUEL COMPONENT
For the Year Ending June 30, 2011

1. Projected Fuel Expense from July 2010 through June 2011

Cost of Fuel	$1,445,319,755	
System Sales	53,473,722	Mwhs
Average Cost Per kWh	2.703	cents / kWh

2. Revenue Difference To be Collected from July 2010 through June 2011

(Over)/Under-Recovery at June 30, 2010	$1,283,206	
Projected S.C. Retail Sales	6,407,677	Mwhs
Average Cost Per kWh	0.020	cents / kWh

3. Base Fuel Cost Per KWH - Projected Period

Average Fuel Cost	2.703	cents / kWh
Revenue Difference	0.020	cents / kWh
Base Fuel Component	2.723	cents / kWh

PROGRESS ENERGY CAROLINAS, INC.

Comparison of Estimated Fuel Revenues and Expenses
SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2010-1-E

Line		Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
(1)	Estimated SC Retail Sales (kWh)	491,383,765	476,070,611	484,438,423	552,106,051	599,299,394	632,498,299	575,294,685	504,336,975
(2)	Estimated Fuel Cost [$/KWH]	0.02852	0.02907	0.02782	0.02895	0.03165	0.02934	0.02450	0.02756
(3)	Fuel Base [$/KWH]	0.03002	0.03002	0.03002	0.03002	0.02723	0.02723	0.02723	0.02723
(4)	Revenue Required	$14,014,265	$13,839,373	$13,477,077	$15,983,470	$18,967,826	$18,557,500	$14,094,720	$13,899,527
(5)	Revenue Billed	$14,751,341	$14,291,640	$14,542,841	$16,574,224	$16,318,922	$17,222,929	$15,665,274	$13,733,096
(6)	Over (Under) Recovery	$737,076	$452,267	$1,065,764	$590,754	($2,648,904)	($1,334,571)	$1,570,554	($166,431)
(7)	Cumulative Over (Under)-Recovery	($3,391,991)	($2,939,724)	($1,873,960)	($1,283,206)	($3,932,110)	($5,266,681)	($3,696,127)	($3,862,558)

Line		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
(8)	Estimated SC Retail Sales (kWh)	458,875,086	515,213,377	586,145,084	521,059,283	494,506,852	478,980,659	486,874,860	554,592,826
(9)	Estimated Fuel Cost [$/KWH]	0.02596	0.02692	0.02558	0.02436	0.02741	0.02380	0.02595	0.02994
(10)	Fuel Base [$/KWH]	0.02723	0.02723	0.02723	0.02723	0.02723	0.02723	0.02723	0.02723
(11)	Revenue Required	$11,912,397	$13,869,544	$14,993,591	$12,693,004	$13,554,433	$11,399,740	$12,634,403	$16,604,509
(12)	Revenue Billed	$12,495,169	$14,029,260	$15,960,731	$14,188,444	$13,465,422	$13,042,643	$13,257,602	$15,101,563
(13)	Over (Under) Recovery	$582,772	$159,716	$967,140	$1,495,440	($89,011)	$1,642,903	$623,199	($1,502,946)
(14)	Cumulative Over (Under)-Recovery	($3,279,786)	($3,120,070)	($2,152,930)	($657,490)	($746,501)	$896,402	$1,519,601	$16,655

Barkley Exhibit No. 7
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

SYSTEM ENVIRONMENTAL COST

SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2010-1-E
TWELVE MONTHS ENDED FEBRUARY 2010

Line		Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09
(1)	**Emission Allowances**	($234,602.42)	$158,382.76	$602,624.91	$458,178.53	$631,465.95	$592,766.92
(2)	**Ammonia**	817,649.66	755,363.11	764,906.16	945,235.28	991,710.32	739,626.49
(3)	**Limestone**	605,240.88	585,871.17	546,699.85	618,857.90	710,395.45	790,442.32
(4)	**Total Environmental Costs**	1,188,288.12	1,499,617.04	1,914,230.92	2,022,271.71	2,333,571.72	2,122,835.73
(5)	**Total Off-System Sales [$]**	(173,804.65)	(60,418.10)	(268,178.10)	(30,275.84)	(33,843.23)	(10,884.86)
(6)	**Total Environmental Expense**	$1,014,483.47	$1,439,198.94	$1,646,052.82	$1,991,995.87	$2,299,728.49	$2,111,950.87
(7)	**SC Retail Sales (kWh)**	514,268,059	450,243,429	446,254,038	532,981,714	594,209,418	604,234,009
(8)	**Total System Sales (kWh) (Exclude Power Agency)**	4,383,385,756	3,822,148,872	3,802,499,057	4,561,692,198	5,017,800,861	5,097,409,080
(9)	**SC Allocation Factor**	0.1173	0.1178	0.1174	0.1168	0.1184	0.1185
(10)	**SC Share of Total Environmental Costs**	$118,998.91	$169,537.64	$193,246.60	$232,665.12	$272,287.85	$250,266.18
(11)	**Amount Billed to SC Customers [$]**	432,333.96	348,057.59	335,092.76	400,399.75	138,441.21	143,826.33
(12)	**Over (Under) Recovery [$]**	$313,335.05	$178,519.95	$141,846.16	$167,734.63	($133,846.64)	($106,439.85)
(13)	**Accounting Adjustments [$]**	-	-	-	(532.82)	-	7,173
(14)	**Cumulative Over (Under) Recovery [$]**	$694,274.24	$872,794.19	$1,014,640.35	$1,181,842.17	$1,047,995.52	$948,729.15

Line		Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Twelve Months Ended Feb-10
(15)	**Emission Allowances**	($48,981.35)	$195,309.93	$275,473.17	$927,917.66	$614,279.97	$650,418.88	$4,823,234.91
(16)	**Ammonia**	564,955.65	532,395.54	530,090.77	678,527.74	716,205.74	747,541.84	8,784,208.30
(17)	**Limestone**	582,901.24	632,108.40	577,796.02	828,749.01	755,400.39	799,445.01	8,033,907.64
(18)	**Total Environmental Costs**	$1,098,875.54	$1,359,813.87	$1,383,359.96	$2,435,194.41	$2,085,886.10	$2,197,405.73	$21,641,350.85
(19)	**Total Off-System Sales [$]**	(3,173.01)	(352,343.67)	(214,455.37)	(621,740.07)	(253,529.76)	(253,464.02)	(2,276,110.68)
(20)	**Total Environmental Expense**	$1,095,702.53	$1,007,470.20	$1,168,904.59	$1,813,454.34	$1,832,356.34	$1,943,941.71	$19,365,240.17
(21)	**SC Retail Sales (kWh)**	521,514,158	495,063,511	465,377,783	501,208,977	617,291,596	557,043,705	6,299,690,397
(22)	**Total System Sales (kWh) (Exclude Power Agency)**	4,593,082,326	3,949,606,098	3,720,845,973	4,399,250,066	5,400,447,065	4,769,193,706	53,517,361,058
(23)	**SC Allocation Factor**	0.1135	0.1253	0.1251	0.1139	0.1143	0.1168	
(24)	**SC Share of Total Environmental Costs**	$124,362.24	$126,236.02	$146,229.96	$206,552.45	$209,438.33	$227,052.39	$2,276,873.68
(25)	**Amount Billed to SC Customers [$]**	133,800.88	116,172.31	108,752.78	128,920.90	169,621.84	149,868.59	2,605,288.90
(26)	**Over (Under) Recovery [$]**	$9,438.64	($10,063.71)	($37,477.18)	($77,631.55)	($39,816.49)	($77,183.80)	$328,415.22
(27)	**Accounting Adjustments [$]**	-	-	-	-	-	(51)	6,590
(28)	**Cumulative Over (Under) Recovery [$]**	$958,167.80	$948,104.09	$910,626.91	$832,995.36	$793,178.87	$715,944.28	

Barkley Exhibit No. 8
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - DOCKET 2010-1-E
CALCULATION OF ENVIRONMENTAL FUEL COMPONENT
For the Year Ending June 30, 2011

Line	Class	Allocation Factor	Share of Projected Costs	Share of (Over)/Under-Recovery at June 30, 2010	Projected July 10 to June 11 SC Retail Sales (kWh)	Projected Demand Billing units (kW)	Projected Average Environmental Fuel Cost	(Over)/Under-Recovered Average Environmental Fuel Cost	Total Environmental Fuel Cost Component
(1)	Residential	40.79%	$1,053,271	($157,955)	2,138,622,214		0.049 ¢/kWh	(0.007) ¢/kWh	0.042 ¢/kWh
(2)	General Service (non demand)	6.64%	$171,340	($25,695)	303,240,283		0.057 ¢/kWh	(0.008) ¢/kWh	0.048 ¢/kWh
(3)	General Service (demand)	52.57%	$1,357,532	($203,583)	3,872,925,947	8,835,266	0.15 ¢/kW [1]	(0.02) ¢/kW [1]	0.13 ¢/kW
(4)	Lighting	0.00%	$0	$0	92,888,938		0.000	0.000	0.000
(5)	Total	100.00%	$2,582,143	($387,233)	6,407,677,381	8,835,266			

SC Environmental Cost Projection

(6)	Projected SC Retail Sales from July 10 to June 11	6,407,677,381
(7)	Projected Total System Sales from July 10 to June 11	53,473,721,757
(8)	Allocation percentage to SC	0.11983
(9)	Projected Environmental Costs July 10 to June 11	$21,548,384
(10)	SC Allocation of Projected Costs	$2,582,143

[1] Rate is based on the Demand Billing Units

Barkley Exhibit No. 9
Docket No. 2010-1-E

Barkley Exhibit No. 10
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

Comparison of Estimated Environmental Fuel Revenues and Expenses

SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2010-1-E

Line		Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10
(1)	Estimated SO2 Expense [$]	469,414	455,718	434,504	481,007	573,436	567,892	419,254	412,861
(2)	Estimated Ammonia & Limestone Expense [$]	1,477,367	1,019,399	1,341,303	1,445,430	1,544,997	1,551,636	1,284,056	1,388,754
(3)	Estimated NOx Expense [$]	50,589	47,961	79,871	91,433	122,385	118,602	84,262	45,484
(4)	Estimated Off-System Sales [$]	(225,911)	(55,993)	(83,844)	(64,737)	(60,937)	(70,424)	(50,497)	(86,954)
(5)	Estimated Total Environmental Expense [$]	1,771,459	1,467,085	1,771,834	1,953,134	2,179,881	2,167,706	1,737,075	1,760,144
(6)	Estimated SC Allocation Factor of Total Expense	0.12202	0.11983	0.11983	0.11983	0.11983	0.11983	0.11983	0.11983
(7)	SC Share of Total Environmental Expense [$]	216,153	175,801	212,319	234,044	261,215	259,756	208,154	210,918
(8)	Residential kWh	162,787,599	124,455,577	128,523,390	185,374,625	222,631,619	222,997,616	180,139,480	129,905,770
(9)	Residential Recovery Rate	0.00032	0.00032	0.00032	0.00032	0.00042	0.00042	0.00042	0.00042
(10)	Residential Recovery [$]	52,092	39,826	41,127	59,320	93,505	93,659	75,659	54,560
(11)	General Service (Non-Demand) kWh	22,717,168	21,019,645	21,952,793	25,784,811	31,262,116	33,426,651	29,938,802	24,852,896
(12)	General Service (Non-Demand) Recovery Rate	0.00028	0.00028	0.00028	0.00028	0.00048	0.00048	0.00048	0.00048
(13)	General Service (Non-Demand) Recovery [$]	6,361	5,886	6,147	7,220	15,006	16,045	14,371	11,929
(14)	General Service Demand kW	748,655	709,516	702,625	755,459	758,620	720,828	816,610	720,265
(15)	General Service Recovery Rate	0.10	0.10	0.10	0.10	0.13	0.13	0.13	0.13
(16)	General Service Demand Recovery [$]	74,866	70,952	70,263	75,546	98,621	93,708	106,159	93,634
(17)	Amount Billed to SC Customers [$]	133,319	116,664	117,537	142,086	207,132	203,412	196,189	160,123
(18)	Over (Under) Recovery [$]	(82,834)	(59,137)	(94,782)	(91,958)	(54,083)	(56,344)	(11,965)	(50,795)
(19)	Cumulative Over (Under) Recovery [$]	633,110	573,973	479,191	387,233	333,150	276,806	264,841	214,046

Line		Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
(20)	Estimated SO2 Expense [$]	368,058	489,356	302,288	294,235	335,454	260,053	237,798	319,222
(21)	Estimated Ammonia & Limestone Expense [$]	1,198,752	1,507,124	1,749,648	1,541,722	1,574,886	1,293,248	1,283,855	1,492,642
(22)	Estimated NOx Expense [$]	38,401	50,960	37,882	34,667	39,118	30,265	53,191	70,224
(23)	Estimated Off-System Sales [$]	(154,629)	(169,224)	(213,050)	(107,577)	(82,958)	(55,672)	(68,485)	(47,877)
(24)	Estimated Total Environmental Expense [$]	1,450,582	1,878,216	1,876,768	1,763,048	1,866,499	1,527,894	1,506,359	1,834,211
(25)	Estimated SC Allocation Factor of Total Expense	0.11983	0.11983	0.11983	0.11983	0.11983	0.11983	0.11983	0.11983
(26)	SC Share of Total Environmental Expense [$]	173,823	225,067	224,893	211,266	223,663	183,088	180,507	219,794
(27)	Residential kWh	130,178,974	202,556,561	262,750,750	184,577,240	163,573,869	124,946,637	128,697,562	185,666,136
(28)	Residential Recovery Rate	0.00042	0.00042	0.00042	0.00042	0.00042	0.00042	0.00042	0.00042
(29)	Residential Recovery [$]	54,675	85,074	110,355	77,522	68,701	52,478	54,053	77,980
(30)	General Service (Non-Demand) kWh	19,414,968	23,085,452	24,979,741	24,487,920	22,818,437	21,098,441	22,022,058	25,852,802
(31)	General Service (Non-Demand) Recovery Rate	0.00048	0.00048	0.00048	0.00048	0.00048	0.00048	0.00048	0.00048
(32)	General Service (Non-Demand) Recovery [$]	9,319	11,081	11,990	11,754	10,953	10,127	10,571	12,409
(33)	General Service Demand kW	642,277	729,033	719,918	787,943	754,634	715,256	708,276	761,604
(34)	General Service Recovery Rate	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
(35)	General Service Demand Recovery [$]	83,496	94,774	93,589	102,433	98,102	92,983	92,076	99,009
(36)	Amount Billed to SC Customers [$]	147,490	190,929	215,934	191,709	177,756	155,588	156,700	189,398
(37)	Over (Under) Recovery [$]	(26,333)	(34,138)	(8,959)	(19,557)	(45,907)	(27,500)	(23,807)	(30,396)
(38)	Cumulative Over (Under) Recovery [$]	187,713	153,575	144,616	125,059	79,152	51,653	27,846	(2,550)

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - DOCKET 2010-1-E
CALCULATION OF TOTAL FUEL COMPONENT
For the Year Ending June 30, 2011

		Cents / KWH				
Line	Class	Base Fuel Cost Component (from Exhibit No. 6)	Base Fuel Cost Component Increased For RECD	Env. Cost Component (from Exhibit No. 9)	Env. Cost Component Increased For RECD	Total Fuel Costs Factor
(1)	Residential	2.723	2.745	0.042	0.042	2.787 [2]
(2)	General Service (non-demand)	2.723		0.048		2.771
(3)	General Service (demand)	2.723		0.000 [1]		2.723
(4)	Lighting	2.723		0.000		2.723

[1] The environmental rate for these customers is 13 cents per kW as shown on Exhibit No. 9.

[2] RECD factor is .8139% and is calculated on Exhibit No. 12.

Barkley Exhibit No. 11
Docket No. 2010-1-E

PROGRESS ENERGY CAROLINAS, INC.

SOUTH CAROLINA RETAIL FUEL CASE - Docket No. 2010-1-E
Revenue Adjustment Factors

Residential Adjustment Factor

1	Billed kWh (12ME 2/28/10)	Per Books	2,252,695,574
2	Billed RECD kWh (12ME 2/28/10)	Per Books	366,677,389 (a)
3	RECD kWh Percent of Total Billed	Line 2 / Line 1	16.2773%
4	RECD Discount	RECD Discount	5.0000% (b)
5	RECD Impact (Weighted Discount)	Line 3 x Line 4	0.8139%

Notes:

(a) Energy billed and discounted pursuant to Residential Energy Conservation Discount, Rider RECD-2B.
(b) Five-percent discount provided under Residential Energy Conservation Discount, Rider RECD-2B.

Progress Energy Carolina's Coal Procurement Practices

1. **Estimate Fuel Requirements.** Fuel requirements are estimated annually using a long-term forecasting simulation model and monthly using a short-term simulation model. Both simulation models factor in load forecasts, system planning and capacity factors for all generating plants.

2. **Establish Inventory Requirements**. PEC uses historic inventory patterns to determine current inventory levels. Currently, we keep coal inventories between 40 – 45 days, depending on the season of the year.

3. **Monitor Ongoing Fuel Requirements**. On an ongoing basis, there is a review and evaluation of current inventory levels, supplier performance and forecasted short-term requirements and commitments to determine additional fuel requirements.

4. **Develop Qualified Supplier List**. A list of qualified suppliers is maintained throughout the year and, to the extent possible, capabilities of suppliers are evaluated including current performance, reserves, coal quality, railroad origination, condition of supplier and loading capabilities.

5. **Bid Requests**. At least once a year, a formal solicitation is sent out to all qualified suppliers for spot and/or longer term coal. PEC seeks staggered expiration terms to reduce the impact of market volatility on customer rates.

6. **Bid Evaluation**. Contracts are awarded after a thorough evaluation process including an economic evaluation, financial and credit review of

the supplier, performance evaluation, coal quality conformance with plant requirements, supplier quality controls, test burns (if necessary) and compliance with federal environmental regulations.

7. **Spot Purchases**. To supplement our fuel supply, short-term spot offers are solicited as needed and purchases made in accordance to needs. These purchases may be limited to a single train.

8. **Monitoring of Purchases**. Purchases are administered, monitored and expedited as needed to ensure compliance with contractual terms.

9. **Quality Control.** The Company requires suppliers to sample, analyze and weigh all coal shipped under the agreements using independent third party labs (ASTM Standards) and certified scales. Three to four samples are typical with one sample being a referee sample should a dispute arise. Sample analyses are used for contractual quality pricing adjustments. Weighing is done at the mine using certified scales and, if no scales are certified at the mine, certified railroad scales are used.

STATE OF NORTH CAROLINA	)	
	)	
	)	VERIFICATION
	)	
	)	DOCKET NO. 2010-1-E
COUNTY OF WAKE	)	

PERSONALLY APPEARED before me, Dewey S. Roberts II who, after first being duly sworn, said that he is Manager – Power System Operations - Carolinas at Progress Energy Carolinas, Inc. and as such is authorized to make this verification; that he has read the foregoing Testimony and knows the contents thereof; and that the same are true and correct to the best of his knowledge, information, and belief.

Dewey S. Roberts

DEWEY S. ROBERTS II

Sworn to and subscribed before me,
this the 6th day of May, 2010.

Marsha H. Manning

Marsha H. Manning, Notary Public

MARSHA H MANNING
NOTARY PUBLIC
WAKE COUNTY, NC
My Commission Expires 10-3-2014

STAREG962

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
DOCKET NO. 2010-1-E
DIRECT TESTIMONY OF
PROGRESS ENERGY CAROLINAS, INC.

WITNESS DEWEY S. ROBERTS II

Q. Mr. Roberts will you please state your full name, occupation, and address?

A. My name is Dewey S. Roberts II (Sammy). I am employed by Progress Energy Carolinas, Inc. (PEC) as Manager – Power System Operations in the Transmission Operations and Planning Department. My business address is 3401 Hillsborough St, Raleigh, North Carolina.

Q. Please summarize briefly your educational background and experience.

A. I graduated from North Carolina State University in 1987 with a B.S. Degree in Electrical Engineering. I also obtained a Master of Science Degree in Electrical Engineering from North Carolina State University in 1990 and a Master of Business Administration Degree from North Carolina State University in 2004. I am a member of the Institute of Electrical and Electronics Engineers (IEEE). I am also a registered Professional Engineer in the state of North Carolina and I am recognized as a Certified System Operator by the North American Electric Reliability Corporation. I joined the Company in 1990 and have held several engineering and management positions in Nuclear Engineering, Engineering and Technical Services, System Operator Training, Portfolio Management, Transmission Services, and Power System Operations. These positions include: Project Engineer, Manager - Transmission Services, and Manager-Power System Operations. In November 2003, I assumed the position of Manager – Power System Operations in the Power

System Operations Section of Progress Energy Carolinas, Inc. System Planning and Operations Department. In my current position as Manager-Power System Operations, I am responsible for managing the safe, reliable, economic, and North American Electric Reliability Council ("NERC") and Federal Energy Regulatory Commission ("FERC") and environmentally compliant operations for the Progress Energy Carolinas' eastern and western balancing authority area power systems.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the operating performance of the Company's nuclear, fossil, combined cycle, combustion turbine, and hydroelectric generating facilities during the period of March 1, 2009 through February 28, 2010 and demonstrate that PEC prudently operated its system for the period under review.

Q. Describe the types of generating facilities owned and operated by the Company.

A. The Company owns and operates a diverse mix of generating facilities consisting of four (4) hydro plants, forty six (46) combustion turbines, three (3) combined cycle units, nineteen (19) fossil steam generating units, and four (4) nuclear units.

Q. Why does the Company utilize such a diverse mix of generating facilities?

A. Each type of facility has different operating and installation costs and is generally intended to meet a certain type of loading situation. In combination, the diversity of the system, in conjunction with power purchases made when doing so is more cost-effective than using a Company owned generating unit, allows the Company to meet the continuously changing customer load pattern in a reasonable, cost-effective manner. The combustion turbines, which have relatively low installation costs but higher operating costs, are intended to be operated infrequently, typically only during times of peak electricity demand. They also provide resources that can be started in a relatively short time for emergency situations. In contrast, the large coal and nuclear steam generating plants have relatively high installation costs with lower operating costs, and are intended to operate in a manner to meet the constant level of demand on the system. Based on the load level that the Company is called on to serve at any given point in time, the Company selects the combination of facilities and power purchases which will produce electricity in the most economical manner, giving due regard to reliability of service and safety. This total cost optimization approach provides for overall minimization of the total cost of providing service.

Q. Please elaborate on the intended use of each type of facility the Company uses to generate electricity.

A. As a general rule, peaking resources such as combustion turbines, are constructed with the intention of running them very infrequently, i.e., only during peak or emergency conditions. Combustion turbines are very effective in providing reserve capacity because they can be started quickly in response to a sharp increase in customer demand, without having to continuously operate the units. Intermediate facilities are intended to operate in a load following manner with periodic startups. They are best utilized to respond to the more predictable system load patterns because the intermediate facilities take some time to bring on-line from a cold shut down state. Additionally, these plants, located across the Company's service territory, contribute to overall system reliability. The Company's intermediate facilities are predominately our natural gas fired combined cycle unit and older coal-fired plants. They generally operate in a load following mode, being ramped up and ramped down to meet system needs. Baseload facilities are intended and designed to operate on a near continuous basis with the exception of outages for required maintenance, modifications, repairs, major overhauls, or for refueling in the case of nuclear plants. The Company's four nuclear units, five Person County coal units, and two Asheville Plant coal units constitute the Company's baseload facilities.

Q. How much electricity was generated by each type of Company generating unit in the 12 month period ending February 28, 2010?

A. For the twelve-month period ending February 28, 2010, the Company generated 62,121,112 megawatt hours of electricity. Nuclear plants generated 45.27%, fossil plants generated 47.34%, combined cycle and combustion turbine units generated 6.25%, and hydroelectric units generated 1.14% of the total amount of electricity generated.

Q. How does the Company ensure that it operates these types of generating facilities as economically as possible?

A. The Company has a central Energy Control Center which monitors the electricity demands within our service area. The Energy Control Center regulates and dispatches available generating units in response to customer demand in a least cost manner. Sophisticated computer control systems match the changing load with available sources of power. Personnel at the Energy Control Center, in addition to being in contact with the Company's generating plants, are also in communication with other utilities bordering our service territory. In the event a plant is suddenly forced off-line, the interconnections with neighboring utilities help to ensure that service to our customers will go uninterrupted. Additionally, the interconnections allow us to purchase power from neighboring utilities with unloaded capacity so that our customers will be served by the lowest cost power available through inter-utility purchases.

Q. How does the Company determine when it needs to purchase power?

A. The Company is constantly reviewing the power markets for purchase opportunities. We buy when there is reliable power available that is less expensive than the marginal cost of the Company's available resources. This review of the power markets is done on an hourly, daily, weekly, and monthly basis. Also, with regard to long term resource planning, we always evaluate purchased power opportunities against self build options.

Q. During the review period March 1, 2009 through February 28, 2010, did the Company prudently operate its generating system within the guidelines discussed in regard to the three types of facilities?

A. Yes. Two different measures are utilized to evaluate the performance of generating facilities. They are equivalent availability factor and capacity factor. Equivalent availability factor refers to the percent of a given time a facility was available to operate at full power if needed. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based on its maximum dependable capacity.

Equivalent availability factor describes how well a facility was operated, even in cases where the unit was used in a load following application. Our combustion turbines averaged 92.32% equivalent availability and a 4.64% capacity factor for the twelve-month period ending February 28, 2010. These performance indicators are consistent with the combustion turbine generation intended purpose. The generation was almost always available for use, but operated minimally. Our intermediate gas-fired combined cycle unit averaged 84.91% equivalent availability and a 59.72% capacity factor for the twelve-month period ending February 28, 2010. The increased capacity factor compared to prior review periods reflects the gas-fired combined cycle unit's ability to effectively take advantage of lower gas prices and is consistent with the intermediate, load following facility's intended purpose. Our intermediate (or cycling) coal fired units, had an average equivalent availability factor of 89.76% and a capacity factor of 53.77% for the twelve-month period ending February 28, 2010. Again, these performance indicators are indicative of good performance and management for intermediate, load following facilities. Our fossil baseload units had an average equivalent availability of 92.41% and a capacity factor of 69.40% for the twelve-month period ending February 28, 2010. Thus, the fossil baseload units were also well managed and operated. For the twelve-month period ending February 28, 2010, the Company's nuclear generation system achieved an actual capacity factor of 91.88%. Excluding outage time associated with reasonable outages, such as refueling, the nuclear generation system's net capacity factor for this period rises to 102.4%. Therefore, pursuant to S.C. Code Ann. § 58-27-865(F), since the adjusted capacity factor exceeds 92.5%, the Company is presumed to have made every reasonable effort to minimize the cost associated with the operation of its nuclear generation.

Q: How did the performance of the Company's nuclear system compare to the industry average?

A: As mentioned in the response to the previous question, during the period March 1, 2009 through February 28, 2010, the Company's nuclear generation system achieved an actual capacity factor of 91.88%. In contrast, the NERC five-year average capacity factor for 2004-2008 for all commercial nuclear generation in North America was 89.02%. The Company's nuclear system incurred a 2.08% forced outage rate during the twelve-month period ending February 28, 2010 compared to the industry average of 3.24%. These performance indicators reflect good nuclear performance and management for the review period.

Q. How did the Company's fossil units perform as compared to the industry?

A. Our entire fossil steam generation fleet operated well during the 12 months ending February 28, 2010, achieving an equivalent availability factor of 90.74% for this period. This performance indicator exceeds the most recently published NERC average equivalent availability for coal plants of 84.66%. The NERC average covers the period 2004-2008 and represents the performance of 914 coal-fired units. Equivalent availability is a more meaningful measure of performance for coal plants than capacity factor because the output of our fossil units varies significantly depending on the level of system load. For the twelve-month period ending February 28, 2010, our baseload fossil units, Asheville 1 and 2, Mayo Unit 1, and Roxboro Units 1, 2, 3, and 4, operated at equivalent availabilities of 95.86%, 96.16%, 88.22%, 92.73%, 86.75%, 93.05%, and 94.08% respectively. Mayo had a relatively lower equivalent availability factor due to a maintenance outage for a boiler inspection and scrubber installation. Roxboro 2 had relatively lower equivalent availability due to a water wall tube inspection outage as well as water wall tube leaks due to tube corrosion fatigue. These water wall tubes are scheduled to be replaced in a spring 2011 maintenance outage.

As I mentioned earlier, the baseload coal units achieved an average equivalent availability of 92.41%. These performance indicators compare well with the industry weighted average equivalent availability factor of 84.69% for 309 similarly sized fossil units.

Q. How did the Company's hydroelectric units perform during the review period?

A. The usage of the hydroelectric facilities on the Company's system is limited by the availability of water that can be released through the turbine generators. The Company's hydroelectric plants have very limited ponding capacity for water storage. The Company operates the hydroelectric plants to obtain the maximum generation from them; but because of the small water storage capacity available, the hydroelectric units have been primarily utilized for peaking and regulating purposes. This operation maximizes the economic benefit of the units. The hydroelectric units had an equivalent availability of 87.53% and operated at a capacity factor of 35.28% for the twelve-month period ending February 28, 2010. The 5 year industry average for hydroelectric generation as published in NERC's most recent report reflects an average equivalent availability of 86.43% and an average capacity factor of 41.25%. The lower equivalent availability factor reflects a major inspection outage at our Walters hydroelectric plant that revealed damage to the intake structure. The repair of the intake structure required an 8 week outage of the Walters hydroelectric plant. Even considering the outage of the Walters hydroelectric plant, the performance indicators show that the Company managed the hydroelectric facilities better than the industry 5 year average for hydroelectric generation equivalent availability.

Q. How might the outcome of the Blewett-Tillery Hydroelectric generation State of North Carolina Section 401 Agency Certification Hearing concerning the relicensing of this facility affect the Company's hydroelectric performance in the future?

A. Should the outcome of the Blewett-Tillery 401 Certification Hearing scheduled for May 2010 result in the Company being required to increase the minimum flow requirements for the Blewett and Tillery hydroelectric facilities compared with those established in the Comprehensive Settlement Agreement for the relicensing of the Yadkin-Pee Dee River Project, FERC Project No. 2206, this outcome would have an impact on fuel expense through reducing on-peak hydroelectric generation.

Q. Are you presenting any exhibits with your testimony?

A. Yes. Roberts Exhibit No. 1 is a graphic representation of the Company's generation system operation for the twelve-month period ending February 28, 2010.

Q. Did the Company prudently operate and dispatch its generation resources during the period March 1, 2009 through February 28, 2010 in order to minimize its fuel costs?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

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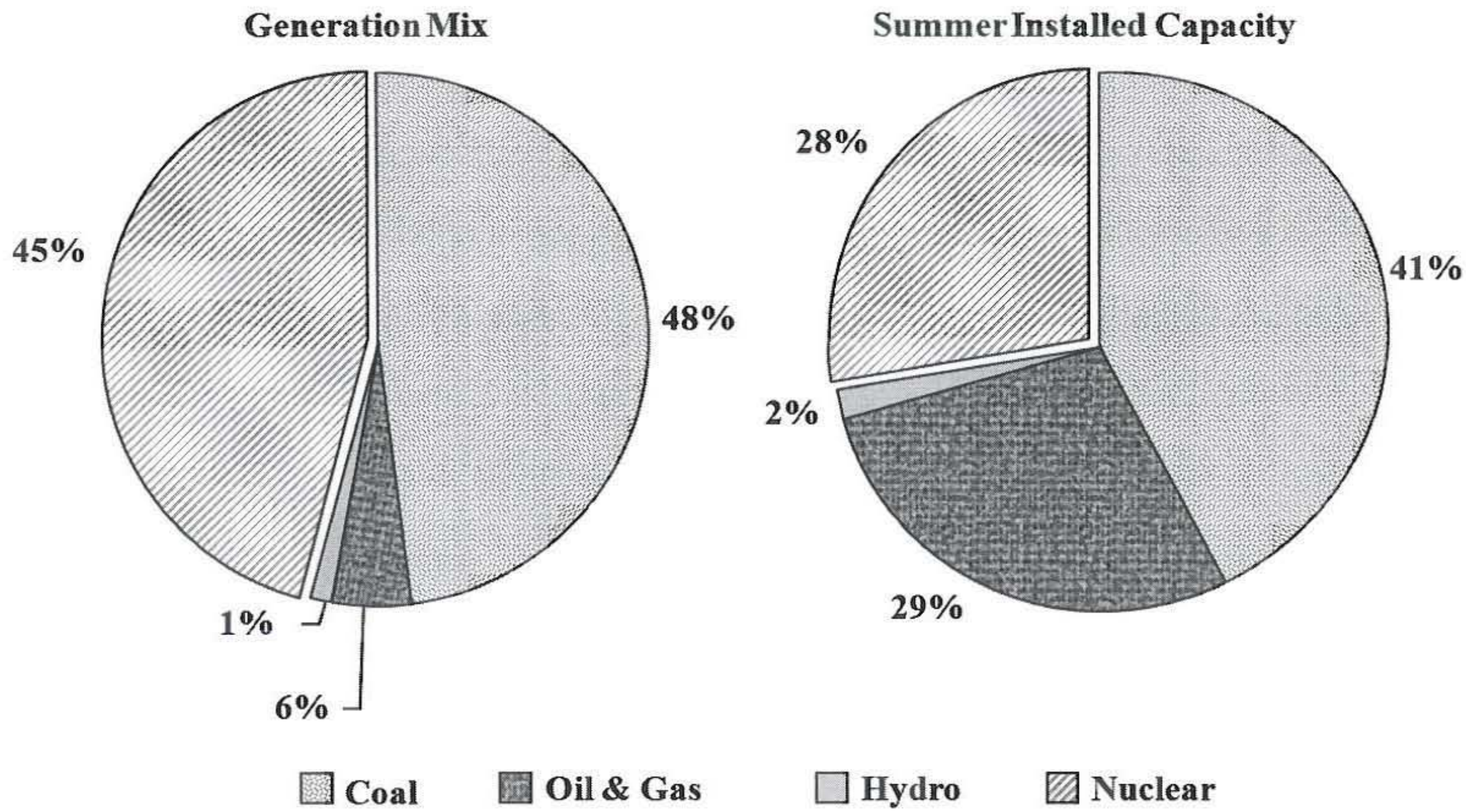
Comparison of Progress Energy Carolinas
Installed Generating Capacity
to Actual Generation Mix
March 1, 2009 through February 28, 2010



Roberts Exhibit No. 1
Docket No. 2010-1-E

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKETING DEPARTMENT

NOTICE OF FILING

DOCKET NO. 2010-1-E

CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC. - ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS.

S.C. Code Ann. Section 58-27-865 (Supp. 2004) established a procedure for annual hearings to allow the Commission and all interested parties to review the fuel purchasing practices and policies of the Company and for the Commission to determine if any adjustment in the fuel cost recovery mechanism is necessary and reasonable.

On May 6, 2010 Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("the Company") submitted testimony in support of a change in rates based solely on the cost of fuel during the period March 1, 2009 through February 28, 2010 and forecasted cost of fuel for the period from March 1, 2010 through June 30, 2011.

The Company has requested that the Commission reduce the base fuel factor established in Docket No. 2009-1-E by .279 cents per kWh. The current base fuel factor is 3.002 cents per kWh, and the reduction is the difference between the current factor and the requested factor of 2.723 cents per kWh.

For the Residential class, the Company requested that the Commission increase the environmental cost component by .01 cents per kWh. The current environmental cost component is .032 cents per kWh, and the increase is the difference between the current factor and the requested factor of .042 cents per kWh. Additionally, the Company has requested that its residential base fuel factor be increased by .022 cents per kWh to account for discounts of 5% that are provided to residential customers served under Rider RECD-2B. The current amount related to the 5% discounts is .025 cents per kWh. The total reduction requested is .272 cents per kWh, and the total reduction is the difference between the total current fuel cost factor of 3.059 cents per kWh and the requested total fuel cost factor of 2.787 cents per kWh.

For the General Service (non-demand) class, the Company requested that the Commission increase the environmental cost component by .02 cents per kWh. The current environmental cost component is .028 cents per kWh, and the increase is the difference between the current factor and the requested factor of .048 cents per kWh. The total reduction requested is .259 cents per kWh, and the total reduction is the difference between the total current fuel cost factor of 3.030 cents per kWh and the requested total fuel cost factor of 2.771 cents per kWh.

For the General Service (demand) class, the Company requested that the Commission increase the environmental cost component by 3 cents per kW. The current environmental cost component is 10 cents per kW, and the increase is the difference between the current factor and the requested factor of 13 cents per kW.

For the Lighting class, the Company requested that the Commission make no change to the current environmental cost of .000 cents per kWh. The total reduction requested is .279 cents per kWh, and the total reduction is the difference between the total current fuel cost factor of 3.002 cents per kWh and the requested total fuel cost factor of 2.723 cents per kWh.

Public Service Commission of SC
Attention: Docketing Department
PO Drawer 11649
Columbia, SC 29211

Date: May 6, 2010